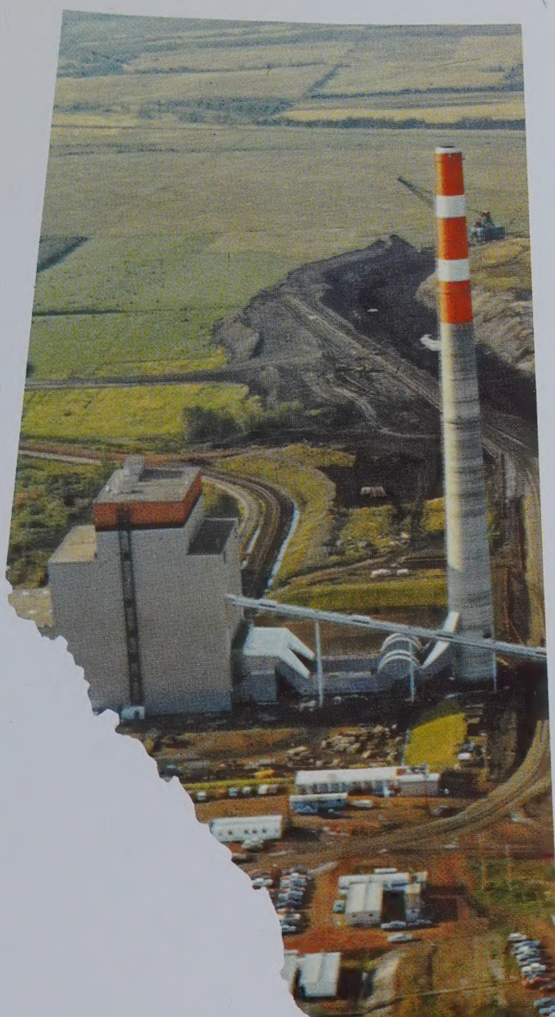
CONSERVATION IN ALBERTA

1971



ENERGY RESOURCES CONSERVATION BOARD
603 SIXTH AVENUE SOUTH WEST - CALGARY 1, ALBERTA

PREFACE

"Conservation in Alberta" is published annually by the Energy Resources Conservation Board to acquaint Members of the Legislative Assembly of Alberta and the public at large with the responsibilities and functions of the Board related to Alberta's oil and gas, hydro and electric, and coal resources. It is not intended as a technical document but is designed to give a broad overview of the Board's activities and to discuss in some detail a few areas of special current interest.

At the 1971 session of the Provincial Legislature the responsibilities of the Oil and Gas Conservation Board, previously restricted to oil, gas and oil sands, were extended to cover pipe lines, hydro and electric energy and coal. The name of the Board was changed to the Energy Resources Conservation Board.

January, 1972.

TABLE OF CONTENTS

COVER PICTURE: Our cover picture is a photograph of the modern coal fired power plant of Calgary Power Ltd. at Lake Wabamun, Alberta. It is reproduced through the courtesy of the Department of Industry and Tourism, Government of Alberta.

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A NEW NAME AND AN EXPANDED ROLE FOR THE BOARD

On June 1, 1971 the name of the Oil and Gas Conservation Board was changed and its role was expanded reflecting a significant development in the administration of the energy resources of Alberta. Since 1938 with the establishment of the Petroleum and Natural Gas Conservation Board, renamed in 1957 as the Oil and Gas Conservation Board, the oil and gas resources of Alberta have been developed under regulations designed to promote resource conservation, equity, efficiency, and safety. The 1971 developments extend this type of regulation to hydro and electric energy resources and to coal.

Initiative for extension of detailed Government surveillance from oil and gas to the other energy resources came from the cities of Calgary and Edmonton who in June 1970, at a hearing before the Oil and Gas Conservation Board, suggested there would be merit in an appraisal of Alberta's requirements of all forms of energy and energy resources and in provision for Government co-ordination of their development. This suggestion sparked a review of the areas of Government responsibility related to energy resource development. Four main areas of Government responsibility were identified.

1. The Disposition of Crown Rights — involving the granting by the Government of rights to explore for and develop the energy resources under control of the Province and the setting of conditions relating to such grants including fees, provision for bonuses and the fixing of royalties. This applies to all of Alberta's energy resources; hydro, oil, gas, oil sands and coal.

2. The Management of the Development of Energy Resources — involving the regulation of the development of the various energy resources of the Province in the interests of safety and efficiency and to ensure that it is carried out without waste and in the public interest.

3. The Management of the Impact on the Environment of the Development of Alberta's Energy Resources — involving the control of pollution of land, surface and subsurface waters and the air and providing for their preservation.

4. The Fixing of Prices and Tariffs. Where Appropriate and of Awards for Necessary Expropriation — involving, where considered necessary in the public interest, the fixing of prices or transmission tariffs of energy resources (or rates of return relating to their supply) and awards to those whose property is expropriated to permit the production or transportation of energy or energy resources.

Disposition of Crown Rights has traditionally been handled in Alberta by the Department of Mines and Minerals in the case of oil, gas, oil sands and coal and by the Department of Agriculture, Water Resources Division for hydro. The review of Government responsibilities confirmed the adequacy of the discharge of these responsibilities and suggested no change other than the transfer of the Water Resources Division to the newly created Department of the Environment, which had already been planned.

Similarly, consideration of the discharge of the Government responsibilities relating to The Fixing of Prices, Tariffs and Awards indicated that they were being effectively handled by the Public Utilities Board and the Arbitration Board under The Right of Entry Arbitration Act.

The Management of Energy Resource Development has or can involve a number of different aspects as listed in the accompanying chart. The review of this matter revealed that the Government responsibilities were being satisfactorily handled in most respects but that there were certain gaps with respect to some of the energy resources. Further, as seen by the Cities, the need for co-ordinated appraisals and development programs was apparent.

In the general area of the oil, gas and oil sands resources most of the functions listed in the chart were being handled by the Oil and Gas Conservation Board subject to approval of the Lieutenant Governor in Council in critical matters. Exceptions were the involvement of the

MANAGEMENT OF ENERGY RESOURCE DEVELOPMENT

INVOLVES	MAY INVOLVE
1. Appraisal of Reserves	1. Protection of Correlative Rights
2. Regulation of Exploration	2. Appraisal of Markets Outside Alberta
3. Regulation of Development	3. Regulation of Extra-Provincial Marketing
4. Regulation of Transportation	
5. Ensurance of Safety	
6. Conservation and Prevention of Waste	
7. Appraisal of Productive Capacity	
8. Appraisal of Alberta Requirements	
9. Recording, Analysis and	
10. Publication of Statistics	

Department of Mines and Minerals in certain specific exploration matters and the administration by that department of The Pipe Line Act under which the construction and operation of intraprovincial pipe lines is regulated. Regulation of extraprovincial marketing of gas and propane is carried out by the Board; such regulation relating to oil has not been considered necessary. Turning to coal, the review revealed that some of the management functions, especially those related to safety in operations, were provided for in The Coal Mines Regulation Act administered by the Department of Mines and Minerals, Mines Division. Some of the functions listed in the chart were found not to be applicable to coal; still others were found applicable but either not to be provided for or to be insufficiently stressed. Among these were provisions for the appraisal of reserves and productive capacity and of markets and regulation of development in the interests of conservation and prevention of waste.

With hydro and electric energy the situation was somewhat analagous to that with coal. The Alberta Power Commission, under The Alberta Power Commission Act, had traditionally handled some of the responsibilities listed in the chart; some appeared not applicable; others were found either not specifically provided for or inadequately so. Again appraisals of reserves, productive capacity and market requirements seemed to need more attention as did the control of power plant and transmission line construction.

In the remaining area of Government responsibility, that of the Management of the Environmental Aspects of Energy Resource Development, a mixed situation was revealed by the review. Furthermore, other studies were underway by the Government related to the establishment of a Department of the Environment. The energy resource oriented study revealed a satisfactory handling of the environmental effects of oil, gas and oil sands development by the Oil and Gas Conservation Board since April of 1970 when the Board was assigned the responsibilities. It confirmed, however, the proper involvement of other departments or agencies of Government and the importance of clear definitions of the roles of each and of co-ordination of activities. With respect to the environmental effects of hydro and electric energy developments and of coal developments, the review revealed gaps in coverage and a need for assignment of further responsibilities.

Taking the review in its entirety it demonstrated a need for an increased Government role in both Energy Resource Management itself and in the control of the Environmental Impact of Energy Developments. It suggested that the responsibilities in these areas of the Oil and Gas Conservation Board

with respect to oil, gas and oil sands should be broadened to include hydro and electric energy and coal and that the related responsibilities of the Department of Mines and Minerals and the Alberta Power Commission should be transferred to the Board. It indicated the desirability of the continued and expanded involvement of the Board in energy resource environmental matters with basic requirements and standards being defined by the Department of the Environment.

The consequences of all this have been the following:

1. The passage in 1971 of The Energy Resources Conservation Act continuing the Oil and Gas Conservation Board as the Energy Resources Conservation Board and defining its broad responsibilities over all energy resources.
2. The passage in 1971 of The Hydro and Electric Energy Act assigning to the Board specific responsibilities relating to resource management and environmental matters with respect to hydro and electric energy. This Act also provided for the rescission of The Alberta Power Commission Act and the disbandonment of the Alberta Power Commission.
3. The passage in 1971, as part of The Energy Resources Conservation Act, but subject to proclamation, of provisions for the transfer to the Board of the administration of
   (a) The Pipe Line Act,
   (b) The Coal Mines Regulation Act, and
   (c) The Quarries Regulation Act.

   By Order of Council 2179/71 these provisions were proclaimed as of January 1, 1972.

Two new Members were added to the Board to strengthen its ability to deal with hydro and electric and coal matters. New staff departments to handle the hydro and electric and coal work were established; plans were made to absorb the Mines Division and the Pipe Lines Division of the Department of Mines and Minerals upon the date of proclamation.

In order most effectively to handle its new responsibilities related to coal, as broadly described in The Energy Resources Conservation Act, the Board believes it desirable that a wholly new Coal Conservation Act be enacted and that extensive revisions be made to the present Coal Mines Regulation Act. Work in drafting provisions for a Coal Conservation Act was carried out in 1971; the draft will be considered in 1972; proposed revisions to the Coal Mines Regulations Act will be prepared during 1972 for consideration in 1973.

The Board is now the Energy Resources Conservation Board. Its responsibilities span the energy resources of Alberta and energy generation and transmission. They are broadly described in the words of The Energy Resources Conservation Act as follows:

" (a) to provide for the appraisal of the reserves and productive capacity of energy resources and energy in Alberta,

(b) to provide for the appraisal of the requirements for energy resources and energy in Alberta and of markets outside Alberta for Alberta energy resources or energy.

(c) to effect the conservation of, and to prevent the waste of, the energy resources of Alberta,

(d) to control pollution and ensure environment conservation in the exploration for, processing, development and transportation of energy resources and energy,

(e) to secure the observance of safe and efficient practices in the exploration for, processing, development and transportation of the energy resources of Alberta,

(f) to provide for the recording and timely and useful dissemination of information regarding the energy resources of Alberta, and

(g) to provide agencies from which the Lieutenant Governor in Council may receive information, advice and recommendations regarding energy resources and energy."

The Board welcomes its new responsibilities and looks forward to justifying the further confidence placed in it by the people of Alberta.

PRODUCTION, SALES AND RESERVES OF ENERGY RESOURCES

CRUDE OIL

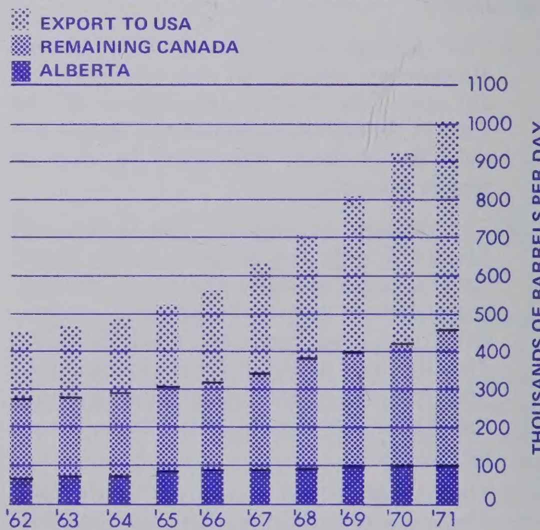
During 1971 production of crude oil in Alberta rose to the highest level in the industry's history with average daily production in excess of one million barrels. Conventional crude oil production averaged 975 thousand barrels per day, while daily production of synthetic crude oil from the Athabasca oil sands averaged 42 thousand barrels per day. Production of conventional and synthetic crude oil increased some 9 and 27 per cent, respectively, from 1970.

Deliveries of Alberta crude oil totalled about 1,010 thousand barrels per day in 1971, a gain of 10 per cent over the previous year. Canadian markets absorbed some 44 per cent or 445 thousand barrels per day. Within Canada, Ontario consumption accounted for approximately 215 thousand barrels per day in 1971 as compared to about 200 thousand barrels per day in 1970. Crude oil shipments from Alberta to British Columbia, Saskatchewan and Manitoba averaged 130 thousand barrels per day in 1971, essentially the same as in 1970. Alberta's own crude oil demand averaged some 100 thousand barrels per day in 1971, an increase of about 9 thousand barrels per day over 1970.

Alberta's crude oil exports to the United States increased 13 per cent over 1970 to average some 565 thousand barrels per day in 1971. Exports to markets east of the Rockies averaged about 365 thousand barrels per day during 1971, an increase of some 55 thousand barrels per day over the 1970 average. Shipments to areas on the United States West Coast increased 10 thousand barrels per day over the previous year averaging some 200 thousand barrels per day.

Commencing in March of 1970, the level of Canadian exports of crude and unfinished oils to States east of the Rockies was limited by a formal quota imposed by the United States Oil Import Administration. The initial quota of 395 thousand barrels per day was subsequently increased to 450 thousand barrels per day, effective January 1, 1971. During August, 1971, the Oil Import Administration allotted an additional 9 million barrels to importers of Canadian crude oil. This had the effect of raising the level of Canadian exports to 475 thousand barrels per day on an annual basis. The growth in deliveries of Alberta crude oil, by area, over the last decade is shown in the accompanying chart.

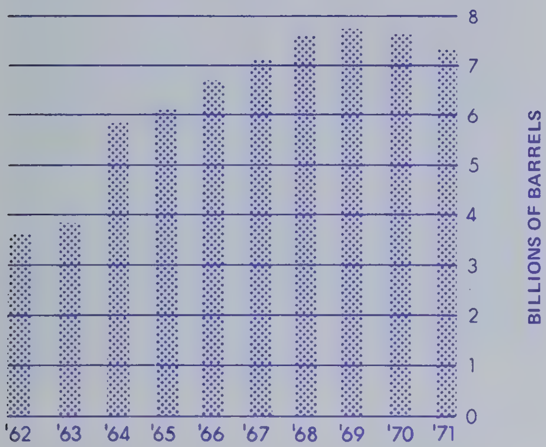
ALBERTA CRUDE OIL DELIVERIES



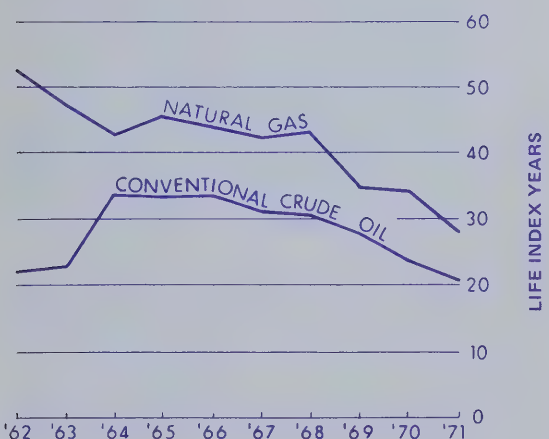
The value of sales of conventional and synthetic crude oil totalled approximately $1,047 million in 1971, an increase of some 20 per cent over the 1970 level of $875 million.

The year 1971 marked the second successive year that additions to conventional crude oil reserves were less than the annual production. Production in 1971 totalled 356 million barrels, compared with 54 million barrels of net reserve additions. The remaining recoverable reserves of Alberta conventional crude oil at year end 1971 totalled 7.3 billion barrels, equivalent to approximately 21 years of supply at 1971 production levels. The historical trends in Alberta's remaining conventional crude oil reserves and the life index of conventional crude oil and natural gas are shown in the accompanying charts.

ALBERTA REMAINING CONVENTIONAL CRUDE OIL RESERVES



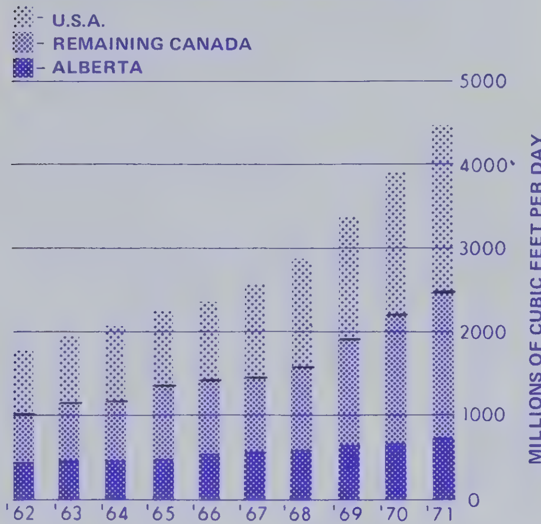
LIFE INDEX OF ALBERTA CONVENTIONAL CRUDE OIL AND NATURAL GAS



NATURAL GAS

Production of marketable natural gas totalled some 1.7 trillion cubic feet of 1,000 Btu gas in 1971, an increase of about 12 per cent over the previous year. Marketable production figures, as used in this report, is the amount of gas available after allowances have been made for gas losses, shrinkage and fuel usage during production and

ALBERTA NATURAL GAS DELIVERIES



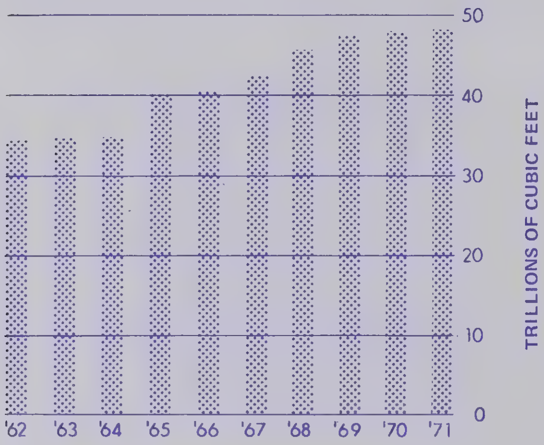
processing operations, as well as volumes which are re-injected into producing reservoirs to maintain reservoir pressure.

Deliveries of Alberta natural gas on a 1,000 Btu basis averaged about 4.4 billion cubic feet per day in 1971. This represents an increase of 0.6 billion cubic feet per day over 1970. Canadian sales in 1971 averaged some 2.4 billion cubic feet per day, as compared to 2.2 billion cubic feet per day, in 1970. Daily exports of Alberta gas to the United States amounted to approximately 2.0 billion cubic feet in 1971, an increase of 0.3 billion cubic feet over the previous year. Total sales of natural gas amounted to some $263 million in 1971, an increase of about 8 per cent over 1970. An historical review of Alberta natural gas deliveries is shown in an accompanying chart.

Alberta's remaining reserves of marketable natural gas on a 1,000 Btu basis at year end 1971 were estimated to total 48.1 trillion cubic feet, approximately the same level as at the end of 1970. This is equivalent to some 28 years of supply at 1971 production levels. The historical trend of Alberta's remaining marketable natural gas reserves is shown in the accompanying chart. As with conventional crude oil, the life index of natural gas has continued to decline over the past few years.

ALBERTA REMAINING MARKETABLE NATURAL GAS RESERVES

(1000 BTU's PER CUBIC FOOT)



NATURAL GAS LIQUIDS

The term natural gas liquids refers to three main products — propane, butanes and pentanes plus — which are produced in association with conventional crude oil and gas. In 1971, production of these products surpassed 1970 levels, continuing a trend established over the previous decade.

Propane production averaged 62 thousand barrels per day in 1971, an increase of about 13 per cent from the previous year. Deliveries to Canadian consumers represented some 48 per cent of the total propane marketed, with shipments to the United States and offshore markets being 39 and 13 per cent, respectively. Remaining reserves were estimated at 737 million barrels at year end 1971, equivalent to some 33 years of supply at the 1971 production rate. Sales of propane totalled about $30 million in 1971, an increase of some 14 per cent over the 1970 level of $26.4 million.

Daily production of butanes averaged 40 thousand barrels in 1971, an increase of almost 18 per cent over 1970. Exports to the United States totalled 24 thousand barrels per day, with the balance of 16 thousand barrels per day being marketed within Canada. Remaining reserves of butanes were estimated to total some 450 million barrels. This represents approximately 31 years of supply at the 1971 production rate. The value of sales increased some 21 per cent over 1970 to total some $18 million in 1971.

Pentanes plus is a product with properties similar to those of light crude oil. Daily production of pentanes plus, including condensate, averaged some 126 thousand barrels in 1971, an increase of about 8 per cent over 1970. The Board estimates the remaining recoverable reserves of pentanes plus at year end 1971 at approximately 1.2 billion barrels, the equivalent of 26 years of supply at 1971 production rates. Sales of pentanes plus, including condensate, totalled some $135 million in 1971, an increase of about 16 per cent over the previous year.

SULPHUR

The year 1971 proved to be a disappointing one for Alberta sulphur producers with production increasing and sales declining. Production totalled some 4.5 million long tons, a 7 per cent increase over 1970. Deliveries totalled some 2.7 million long tons, a decrease of about 13 per cent over the previous year. Remaining recoverable reserves of sulphur, excluding sulphur from the Athabasca oil sands, were estimated to total 188 million long tons at year end 1971. The inventories of Alberta sulphur increased by about 1.8 million long tons during 1971 to total some 5.2 million long tons at year end.

Sulphur prices received by Alberta producers have fluctuated widely over the past decade. Commencing in 1962, the average annual price per long ton of sulphur was $14.81, declined to a low of $11.04 by 1964, increased to a high of $34.54 in 1968, and then decreased to about $7.50 in 1971. The value of sulphur sales totalled some $19.2 million in 1971, a decrease of about 30 per cent from the 1970 level of $27.4 million.

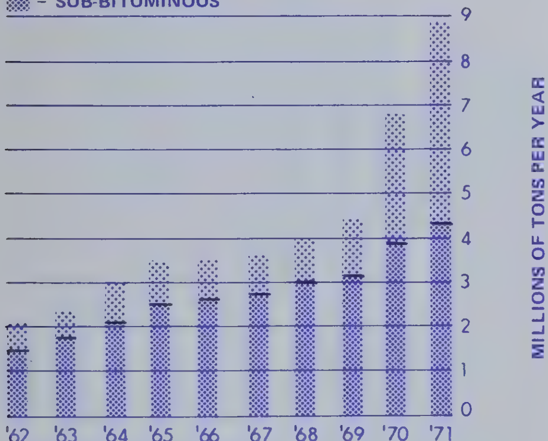
COAL

The production of coal in Alberta reached record levels in 1971. Total output was some 8.9 million tons in 1971, an increase of 31 per cent over the previous year. The 1971 coal production was the highest experienced since 1949 when 8.6 million tons of coal were mined.

Alberta production of bituminous coal, mainly exported to Japan where it is used for coking purposes, totalled some 4.6 million tons in 1971. This represents an increase of about 60 per cent over 1970 production levels and some 283 per cent over levels attained in 1969. Sub-bituminous coal production increased to 4.3 million tons in 1971, an increase of some 10 per cent over the 1970 level. Sub-bituminous coal is used principally by electric utilities for thermal power generation in Alberta. Sales of Alberta coal totalled some $37 million, an increase of approximately 38 per cent over 1970 when sales totalled $26.7 million. Historical reviews of Alberta coal production and sales are shown in the accompanying charts.

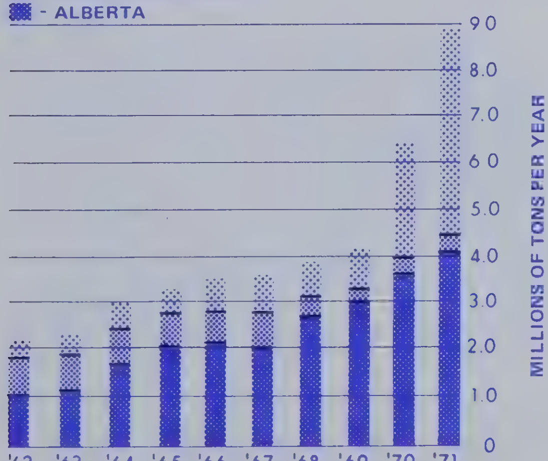
ALBERTA COAL PRODUCTION

- BITUMINOUS
- SUB-BITUMINOUS



ALBERTA COAL SALES

- EXPORT
- REMAINING CANADA
- ALBERTA



The Board has not to date prepared estimates of Alberta's coal reserves. It does, however, plan to undertake an extensive study of this matter in the near future. Statistics presented by B. A. Latour to the 22nd Canadian Conference on Coal (1970) indicate (with some interpretation by the Board) that Alberta's reserves of bituminous and sub-bituminous coal are in the order of 37.3 and 9.9 billion tons respectively. Measured (proved) reserves of bituminous coal were estimated to be 1.0 billion tons and of sub-bituminous coal, 1.2 billion tons.

ELECTRICITY

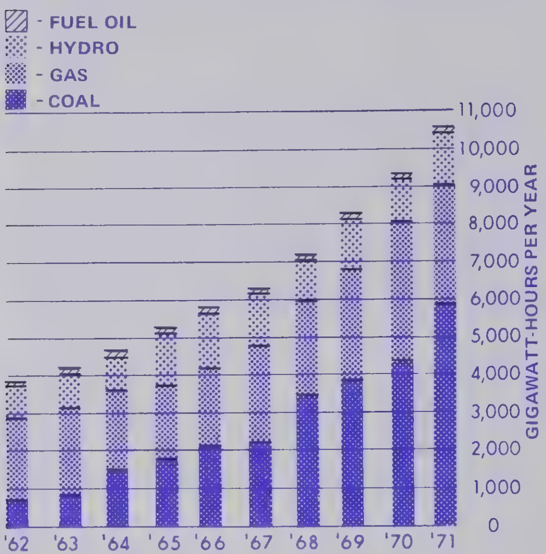
The generation of electric energy in Alberta has shown a remarkably high and continuous rate of growth over the last decade. During this period, the output of electricity by electric utility companies has increased at an average annual rate of slightly in excess of 12 per cent, increasing from some 3,800 gigawatt-hours (10^9 watt-hours) in 1962 to approximately 10,500 gigawatt-hours in 1971.

Electricity generated from hydro sources was some 1,400 gigawatt-hours in 1971. In the southern part of the Province most of the available hydro sites have been developed and consequently Alberta's electricity supply from hydro sources as a share of total generation has diminished over the last decade, decreasing from some 23 per cent in 1962 to approximately 14 per cent in 1971.

In the year 1971, total thermal electric energy generation increased some 12 per cent over 1970, totalling about 9,100 gigawatt-hours. Generation of electricity from coal and gas operated facilities accounted for about 65 and 34 per cent, respectively, of the total thermal generation in 1971. Fuel oil was responsible for only 1 per cent of the total thermal generation, approximately the same as in 1970. The accompanying chart shows the growth of electric energy generation in Alberta.

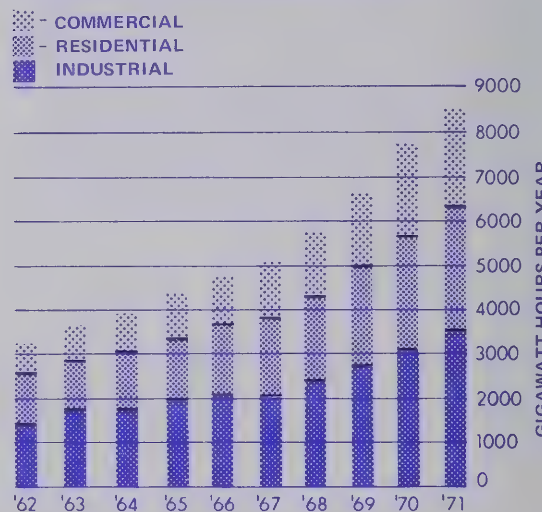
Sales of electricity to ultimate customers by electric utilities in Alberta totalled some 8,500 gigawatt-hours in 1971, as compared to about 7,600 gigawatt-hours in 1970. Sales to industrial consumers amounted to some 3,500 gigawatt-hours or some 41 per cent of total

ALBERTA ELECTRIC ENERGY GENERATION



sales. Residential and commercial sales in 1971 totalled some 2,800 and 2,200 gigawatt-hours, respectively. The difference between the generation and sales of electrical energy in 1971 can be principally accounted for by line losses, with exports and production facility consumption accounting for smaller amounts. An historical review of sales is shown below.

ALBERTA ELECTRIC ENERGY SALES



ENHANCED RECOVERY OF CRUDE OIL

One important way of increasing the total crude oil supply is to improve the per cent of the original oil in place that is recovered. As the exploration for and development of the oil and gas pools in Alberta's underlying sedimentary basin reaches a mature stage, increasing emphasis will be placed on increasing the recovery factor of developed pools. Conventional oil pools discovered in Alberta to the end of 1971 initially contained about 32 billion barrels of oil in place. Even though very substantial expenditures of time, money and materials have been directed towards improving the natural recovery processes of most of these oil reservoirs, it is currently estimated that only some 11 billion barrels or about one-third of the original oil in place will have been recovered when the pools are abandoned. An increase of only one or two per cent in the average ultimate recovery would be equivalent to the discovery of a significant new oil play and would be sufficient to offset a full year or more of production.

Enhanced recovery requires the introduction of additional energy to augment an oil reservoir's natural pressure energy — usually through the injection of water, gas or solvent to displace the crude oil through the reservoir rock toward the producing wells. The early application of such energy to a majority of Alberta's oil reservoirs has increased the Province's overall ultimate recovery factor by some 13 per cent or about one half again as much as that expected by natural recovery processes.

The Board is responsible for reviewing the technical and economic feasibility of all oil industry proposals for enhanced recovery

schemes and approving of such schemes, with modification and improvement as required and after consultation with the operator. Several enhanced recovery schemes have resulted from the Board's practice of initiating feasibility studies, followed by liaison with the operator and subsequent approval of an operator's proposal. Surveillance of all operating enhanced recovery schemes is also the responsibility of the Board.

To the end of 1971, the Board has approved a cumulative total of about 350 enhanced recovery schemes distributed throughout the Province and affecting in whole or in part 200 individual oil pools. For purposes of comparison, ultimate oil reserves for the Province were about 11 billion barrels at the end of 1971 of which 3.5 billion barrels is directly attributed to recovery improvement by water injection. In those same projects it is estimated that recovery under natural depletion would have been just under 3 billion barrels. In other words, water injection has successfully doubled the reserves in those pools.

Solvent flooding utilizes the placement of a bank of gas rich in propane and butane that is completely miscible or soluble with crude oil in the rock pores, with the consequence that nearly all of the crude oil is flushed from the pores in any region of the reservoir that can be contacted by the miscible fluid. Eight solvent flood schemes in 16 pools are forecast to ultimately produce about one billion barrels of crude oil whereas the pools were expected to produce only 0.7 billion barrels under natural recovery mechanisms.

Enhanced recovery by displacement of oil with immiscible gas injection is a less frequently used process largely because the incremental gain in oil recovery over primary depletion does not usually offset the advantages of water injection or the economic value of the gas as an otherwise saleable commodity. There are ten immiscible gas injection schemes in ten pools in the Province, and these schemes are expected to ultimately produce 0.16 billion barrels of crude oil compared to 0.14 billion barrels under natural recovery mechanisms.

Respecting surveillance of existing enhanced recovery schemes, some 340 reports on their progress were received in 1971. These reports, in conjunction with the Board's computer based compilation of monthly production and injection balances, were used to review the performance of about 300 of these projects. In the reviews the producing gas-oil ratio, water-oil ratio and pressure statistics were compared to the approved specifications for the scheme. Where shortcomings were observed, notification of the operator of the scheme resulted in most cases by early rectification of the situation. In about ten instances the oil production allowable authorized for the scheme was reduced from the enhanced recovery allowable level to an allowable commensurate with natural depletion pending solution of the operational problems associated with the lack of compliance with the terms of the approval.

In addition to the production and injection reviews of the enhanced recovery projects discussed above, more technically detailed performance reviews were completed in three horizontal displacement solvent floods, one vertical displacement gas flood and eight water floods. Results varied widely, with negative performance relative to that expected being indicated in two solvent floods and three of the water floods. The remainder of the reviews indicated that performance to date was consistent with the initial predictions.

Fifty new but small enhanced recovery schemes authorized during 1971 will eventually contribute about 75 million barrels more crude oil to the pools' recoverable reserves than if they were naturally depleted. Most of these newly approved schemes are not yet operational so that these reserves have not yet been added to the Province's total oil reserves. About 40 million barrels of the increment results from schemes in the increasingly active heavy crude oil producing areas of southern Alberta. Another area of interest, in view of its complexity, is the Zama area in northwestern Alberta. Five integrated water flood schemes in the area involving 29 small pinnacle reef pools, each having only one well, were approved during 1971. Operators in these pools generally plan to cease oil production from one or more of the wells and use the shut-in wells for water injection, thereby pressure maintaining the remaining producing pools in the scheme through the continuous aquifer underlying the

group of pools. These schemes, however, will increase oil recovery by only about 6 million barrels.

A major review of the enhanced recovery prediction as compared to the actual performance of the Pembina Cardium Pool water flood was completed in 1971, the instigation for the study coming from conflicting technical evidence submitted by many of the well owners in the pool. The Board concluded that there was not sufficient water flood history to warrant a change in the assigned water flood recovery factor. However, the review of the oil in place of this unusually large pool resulted in its downward revision from 7.74 billion to 7.44 billion barrels and the commensurate reduction in recoverable barrels atrributable to water flood areas was 70 million barrels. Additionally, part of a large water flood scheme in the Pembina Cardium pool reverted to primary depletion due to adverse reservoir rock characteristics, which were causing premature water production at high rates, indicating a poor ultimate oil recovery. The corresponding decrement to ultimate recoverable reserves was about 11 million barrels of crude oil. The net effect on the Province's enhanced recovery reserves assigned during 1971 has been to cause, for the first year in more than a decade, a negative recoverable reserve attributable to enhanced recovery. This result illustrates how a nominal downward adjustment in assigned reserves for a major pool such as Pembina Cardium may overshadow important upward adjustments in numerous smaller pools in a given year.

During 1971, the Board reviewed some 30 light and medium crude oil pools and 15 heavy crude oil pools as possible future candidates for enhanced recovery. Additionally, the Board continued to press for implementation of enhanced recovery operations in the Zama area. The area contains about 300 small pinnacle reef pools of which only 73 have been committed to some form of enhanced recovery. Under natural depletion, reserves from the area may approach 200 million barrels. Due to the small oil reserves of each pool, most of which have only one well, and the tendency for the pools to produce "coned-in" water from the underlying aquifer, industry has been reluctant to add to the risk of flood out of wells which might result from water injection. While the Board has recognized the need for careful analysis, it will continue to promote fluid injection operations where feasible based on its belief that normal water flood conditions could add perhaps 50 million barrels of reserves to the area.

During 1971, the Board decided to approve, if so authorized by the Lieutenant Governor in Council, an application by Syncrude Canada Ltd. for an increase from 80,000 barrels per day to 125,000 barrels per day in its permitted rate of production of synthetic crude oil derived from extraction of bitumen from mineable oil sands. This very large mining, extraction and refining plant will be situated northwest of the presently operational plant of Great Canadian Oil Sands in the Fort McMurray area and is scheduled to be on production during the latter half of 1976. The environmental factors of air, water and soil pollution were given careful consideration and the Board's approval of the scheme specifies standards for the monitoring and control of industrial pollution in the area. The Great Canadian Oil Sands bitumen operation had its most successful year to date, producing at an average rate of some 42,000 barrels of synthetic crude oil per day as compared to its approved rate of 45,000 barrels per day.

Experimental schemes in both the Athabasca and Cold Lake oil sands deposits continued at a level of activity somewhat higher than in the past two years. There were five experimental thermal schemes active at year end.

CONSERVATION OF SOLUTION GAS

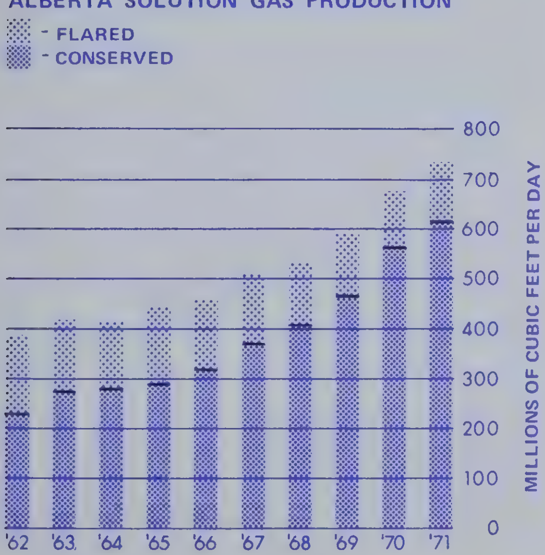
Oil under pressure in its natural state in the reservoir contains gas in solution and when the oil is produced much of this gas separates from the oil as the pressure is released. The gas may be gathered and put to a useful purpose, or it may be flared. The flaring of solution gas has been recognized as a waste for many years. To ensure that solution gas is conserved wherever conservation is feasible and to retain a measure of control over conservation schemes, the Board issues Gas Conservation (GC) orders. By the end of 1971, 44 such orders had been issued.

The Board's GC orders stipulate that the licensee of each well is responsible for the conservation of any gas produced from the well within limits specified in the order. The flaring of some of the raw gas is usually permitted, the amount being that which experience indicates would not be economical to conserve having regard for the nature of the production and conservation system. The licensee of each well is responsible for all flaring of his gas, including any which occurs at the well, the battery, the gathering system and the gas processing plant. Each GC order contains a provision whereby wells from which it is not feasible to conserve the gas may be exempted by the Board.

A number of conservation schemes not covered by GC orders are operating within the Province. Part of the Rainbow area where gas is being used to pressure maintain oil pools is in this category. In order to control the flaring of gas in such systems the Board has been issuing GC orders over the past year to cover such schemes.

As a result of the efforts of the Board and industry to improve gas conservation, some 84 per cent of the 1971 solution gas production in the Province was conserved, compared with 83 per cent in 1970, and with 57 per cent ten years ago. The accompanying chart illustrates the trend in the volume of solution gas produced and the progress made in controlling the amount of solution gas which is flared.

ALBERTA SOLUTION GAS PRODUCTION



Over three-quarters of the solution gas conserved during 1971 was processed for sale as marketable gas, propane, butanes, pentanes plus and sulphur. The remainder was injected into underground reservoirs either for storage or to increase the recovery of crude oil.

A continuation of the high demand for oil during 1971 resulted in high production rates of oil and hence of solution gas. The rates resulted in higher than usual flaring rates in fields where gas conservation is not taking place. In areas where gas is being conserved the high rates exceeded the capacity of the plant and system in certain instances. Certain plants were expanded and additionally, a variety of interim measures were adopted to meet the conservation requirements at the increased production rates. One of the most important of these was the storage of raw gas in underground reservoirs until the gas processing plant capacity could be increased.

To efficiently provide for the conservation of solution gas from a field or group of fields, the possibility of a future increase in gas production rates and the effect this may have on conservation must be carefully considered. As a result of increasing gas production rates, gas conservation facilities must either be designed with excess capacity or be expanded as necessary during the producing life. This has been clearly shown on the conservation complex which gathers solution gas from the Swan Hills, Swan Hills South, Virginia Hills and Judy Creek fields and processes it in the Judy Creek Gas Processing facilities. Oil production began in the area in 1959 and the oil pools were rapidly developed. The production of solution gas increased to the point where it was considered economic to gather and process the gas for sale. In 1962 an approval was issued by the Board for the construction and operation of gas gathering and processing facilities for the Swan Hills, Judy Creek and Virginia Hills fields. These facilities began operating in 1963 with a design capacity of 40 million cubic feet of raw gas per day.

In 1965 the scheme was expanded to include the Swan Hills South field with the raw gas capacity of the plant being increased to 55 million cubic feet per day. The production of raw gas continued to increase with the result that the gas processing facilities were again

expanded to a design capacity of 85 million cubic feet of raw gas per day in 1968 but further increases in oil allowables resulted in an apparent gathering and processing capacity shortage by the end of 1970.

Early in 1970 the Board became concerned that the gas conservation level being attained was not satisfactory and the matter was reviewed at several meetings with well owners. As a result raw gas in excess of the plant capacity was injected into the formation of origin in the Judy Creek, Swan Hills and Virginia Hills fields and a portion of the raw gas from the Swan Hills South field was sold without processing.

Also in 1970 approval to increase the raw gas capacity of the processing plant by an additional 60 million cubic feet per day was issued by the Board. Early in 1971 a further request for an additional 30 million cubic feet per day of capacity was requested by the plant operator and approved by the Board bringing the presently approved total plant capacity to 175 million cubic feet per day. The added facilities went on stream late in 1971 and it is likely that further additions may be necessary in the near future. The growth of the Swan Hills — Judy Creek Gas Conservation complex from 40 to 175 million cubic feet per day in four stages during the 1963-1971 period illustrates the difficulty of reconciling the capital needs for such expansion with the uncertainties of crude oil and solution gas production forecasts.

A beneficial by-product of the conservation of solution gas is the abatement of air pollution. On this account the Board increases its efforts to bring about gas conservation in inhabited areas, even though the economics may be marginal. In assessing the economics of the conservation of solution gas containing hydrogen sulphide, the expenditures necessary for pollution control if conservation did not take place are considered. The most recent projects which have been installed to gather and process gas containing significant amounts of hydrogen sulphide are in the Erskine, Clive, Alix, Olds, Simonette, Sundre and Sturgeon Lake South fields. Facilities are currently being installed to process the gas and thus reduce air pollution in the Joffre field near Red Deer.

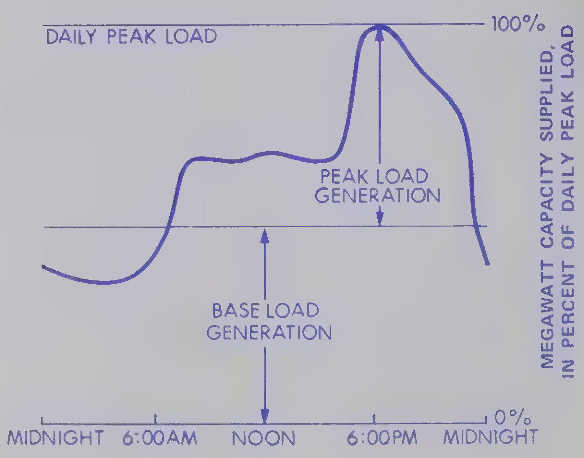
HYDRO AND ELECTRIC ENERGY IN ALBERTA

Alberta's requirements for electric energy have grown dramatically over the past decade reflecting population growth, extension of service and the increasing industrialization of the Province. This is shown in the chart presented on page 10. For the past several years residential, commercial and industrial consumption has been 33, 26, and 41 per cent of the total.

A characteristic of the electric energy requirement is its daily variation over the year and its hour-by-hour variation over the day. The daily requirement is normally greatest in late December when temperatures are low and lighting loads are highest. The typical variation in hourly demand on a winter day for Alberta as a whole is illustrated on the accompanying chart. In the chart the demand is shown as a per cent of the peak demand which typically occurs at about 5:30 p.m. The chart illustrates that the total demand for electric energy may be

THE DAILY VARIATION OF ELECTRIC LOAD FOR A WINTER WEEK-DAY IN ALBERTA

(ILLUSTRATIVE ONLY)



considered to be made up of two portions — a base load reflecting small hour by hour variations and a peak load which occurs during the most active hour of a typical day. This characteristic of the demand is of major significance in the planning of the most economical manner of generation and transmission of electric energy. The percentage relationship between the annual average demand and the peak demand is the so-called load factor. The load factor for Alberta's total electric energy requirements is about sixty per cent. This means that facilities must be able to provide for peak demands for electric energy which are about one and two thirds times the annual average demand.

Generation and transmission of electric energy in Alberta is by a mixture of private, investor-owned companies and municipally-owned utilities. Calgary Power Ltd. generates electric energy in the southern part of the Province, Canadian Utilities Limited and Northland Utilities Limited in the eastern and northern areas, Edmonton Power (owned by the City of Edmonton) in Edmonton, and the cities of Medicine Hat and Lethbridge in their respective cities. Small, isolated generating stations which have not been connected to the inter-connected system of the Province serve areas such as Jasper townsite and Fort McMurray. The power plants of Calgary Power Ltd. are inter-connected with one another by high voltage transmission lines and, for the large part, all major plants of the Province are inter-connected making possible the interchange of energy among the various electric utilities. The inter-connections permit each utility to plan for the efficient generation of its own base and peak load and for joint planning among the utilities.

Facilities in Alberta have developed with the growth in the demand for electric energy and in a manner reflecting its nature — the base and peak load components. The location and type of the major facilities and inter-connecting transmission lines are shown on the accompanying map. The ownership and principal characteristics of the major power plants are given in a following table. Base load energy is provided mainly from large thermal power plants; peak loads from hydro plants, gas turbines, diesel units, and small thermal units. Alberta's total generating capacity at year end was 2,553 megawatts divided approximately as follows:

Type of Power Plant	Per Cent of Capacity
Large Hydro	26.6
Large Coal Fired	39.1
Large Gas Fired	26.8
Plants less than 50 megawatt (small Thermal, Gas Turbine, and Diesel)	7.5
Total	100.0

Contrasting with the distribution of capacity is that of the actual total energy generation. The total generation of some 10,500 megawatt-hours in 1971 was distributed as follows:

Type of Power Plant	Per Cent of Energy
Large Hydro	14.
Large Coal Fired	56.
Large Gas Fired	26.
Plants less than 50 megawatt (small Thermal, Gas Turbine, and Diesel)	4.
Total	100.

MAP OF

ALBERTA

SHOWING

THE INTERCONNECTED
TRANSMISSION SYSTEMS OF ALBERTA

LEGEND

▲ GENERATION
(Stations less than 10 MW not shown)

—— ALBERTA POWER LIMITED 144 & 240 Kv
Transmission (72 Kv not shown)

– – – CALGARY POWER LTD. 138 & 240 Kv
Transmission (69 Kv not shown)

Note: Only main transmission routes are shown.

HYDRO AND ELECTRIC ENERGY GENERATION IN ALBERTA

Location	Type	1971 Capacity (Megawatt net)	Principal Use*
Calgary Power Ltd.			
Bow River System.	Hydro	325	Peak load and river control
North Saskatchewan River System	Hydro	355	Peak load and river control
		680	
Wabamun	Gas fired	68	Reserve
Wabamun	Coal fired	501	Base load
Sundance	Coal fired	286	Base load
		855	
		1535	
Edmonton Power			
Rossdale	Gas fired	392	Base load
Clover Bar	Gas fired	165	Base load
		557	
Canadian Utilities, Limited & Northland Utilities Limited (Alberta Power Limited)			
Battle River	Coal fired	212	Base load
Rainbow	Gas fired	58	Peak load
Small power plants	Gas or oil fired	119	Peak load
		389	
Medicine Hat			
City power plant	Gas fired	41	Base load
Lethbridge			
City power plant	Gas fired	31	Peak load
Province as a whole		2553	

* Principal use is shown although a number of multiple unit plants such as Rossdale combine base load and peak load operation.

The making of major decisions involving enormous capital expenditures and affecting the quality of service to consumers in Alberta has been a feature of the hydro and electric industry of Alberta for the past 60 years but the significance of the decisions to be made in the immediate and continuing future is greater than ever before. The choice between thermal and hydro power will influence the cost of energy, requirements of fossil fuels, and the quality of the environment. Whether a thermal power plant is fueled with coal or gas affects cost, the gas available for other uses and the environment. The size of a power plant is a major factor in determining the cost of electric energy from that plant. Other factors constant, a 500 megawatt generating unit can generate energy at about 70 per cent of the unit cost of that from a 100 megawatt generating unit. The overall cost of energy depends on the plants which are inter-connected to form a generation system but the principle of economy of scale continues to be valid.

Industry, with guidance from the former Alberta Power Commission, has given consideration to these aspects of planning in the past. The Energy Resources Conservation Board

has an important role to play in the future. Its objectives will be to see that the most effective use is made of Alberta's varied resources for electric energy generation and that generation and transmission is efficient, economic and in the broad public interest. The Hydro and Electric Energy Act requires that the Board review all proposals for new generation and transmission facilities and that its approval, with the authorization of the Lieutenant Governor in Council, be given before new facilities or significant additions to existing facilities are constructed. Effective resource utilization, efficient generation and the impact on the environment will be the major considerations. In regard to the impact on the environment, the Board and the Department of the Environment will co-operate in deciding what conditions should apply in a certain case.

GAS PROCESSING

INTRODUCTION

Natural gas processing in Alberta commenced with the construction of a plant at Turner Valley in 1933 to process solution gas which was until then being flared. The Turner Valley plant is still in operation today but has been significantly modified. Two other small plants were constructed in the field in later years. These three plants made up the total natural gas processing industry in Western Canada until the early 1950's.

The first plant to produce elemental sulphur from natural gas was built in the Jumping Pound area near Cochrane and was placed on stream in 1951.

Many other plants have been constructed since the early days of the industry to supply the ever increasing demand for natural gas, natural gas liquids and sulphur.

REASONS FOR PROCESSING NATURAL GAS

Natural gas, as produced from subsurface reservoirs, is usually unsuitable for consumption as a fuel without some processing to remove co-products and impurities. Raw natural gas is a mixture of hydrocarbon compounds and often contains water vapor, hydrogen sulphide and carbon dioxide. The water must be removed from the gas to prevent hydrate formation in the gas transmission pipe lines. Liquid hydrocarbons are extracted from the natural gas to improve its burning and transmission properties. The liquid hydrocarbons extracted are the natural gas liquids in the form of propane, butanes and pentanes plus. Hydrogen sulphide must be removed because of its toxicity, objectionable odor and its corrosive properties. The hydrogen sulphide is converted to elemental sulphur, an industrial product. Carbon dioxide is removed because it would otherwise lower the heating value of the gas and it has corrosive properties. These extraction operations are all carried out at gas processing plants with the result that a final purified natural gas product is produced for space heating and industrial uses.

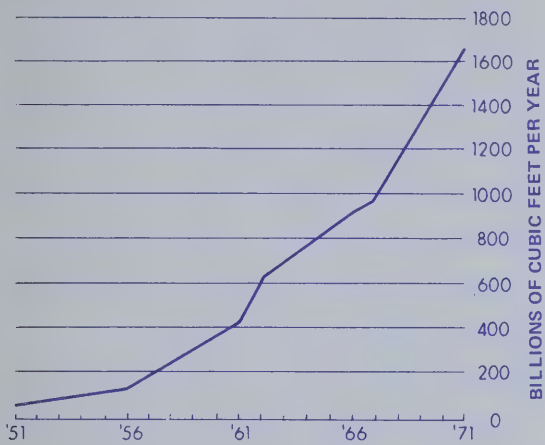
GROWTH OF THE INDUSTRY

Since 1950 the number of processing plants in the Province has increased from three to some 150. Sixty of the plants process gas containing hydrogen sulphide, while the remaining 90 plants process sweet gas not containing hydrogen sulphide. In addition to the conventional gas processing plants in operation, four plants in Alberta reprocess gas for the extraction of natural gas liquids.

The rapid growth of the industry has contributed much to the economy of the Province through gas plant construction projects alone. Gas processing plant construction values for projects completed during 1971 set a record of 220 million dollars as compared to 1970 construction costs of 55 million dollars.

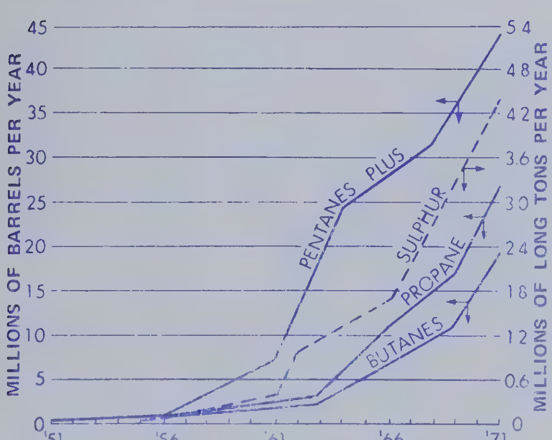
The accompanying chart shows that Alberta sales of natural gas have increased over 30 fold in the last 21 years, from 50 billion cubic feet in 1950 to 1,650 billion cubic feet in 1971.

ALBERTA SALES OF MARKETABLE GAS
(1000 BTU's PER CUBIC FOOT)



The co-products of natural gas have shown a similar growth pattern as shown by a following chart. The annual production of propane, which

PRODUCTION OF NATURAL GAS CO-PRODUCTS



is used for space heating and as a petrochemical feedstock, has increased from some 250 thousand barrels in 1950 to about 26.9 million barrels in 1971. The annual production of butanes, used in the refining and petrochemical industries, has increased from about 30 thousand barrels to 19.5 million barrels and the annual production of pentanes plus, also a refinery feedstock, has grown from approximately 460 thousand barrels to 44.2 million barrels over the same period. Sulphur production has shown similar growth from no production in 1950 to some 4.5 million long tons in 1971. The present world oversupply of elemental sulphur has made it necessary for many sulphur producers in the Province to stockpile much of their sulphur production. Total inventories of sulphur at the end of 1971 were 5.12 million long tons.

GAS PROCESSING PLANT TYPES

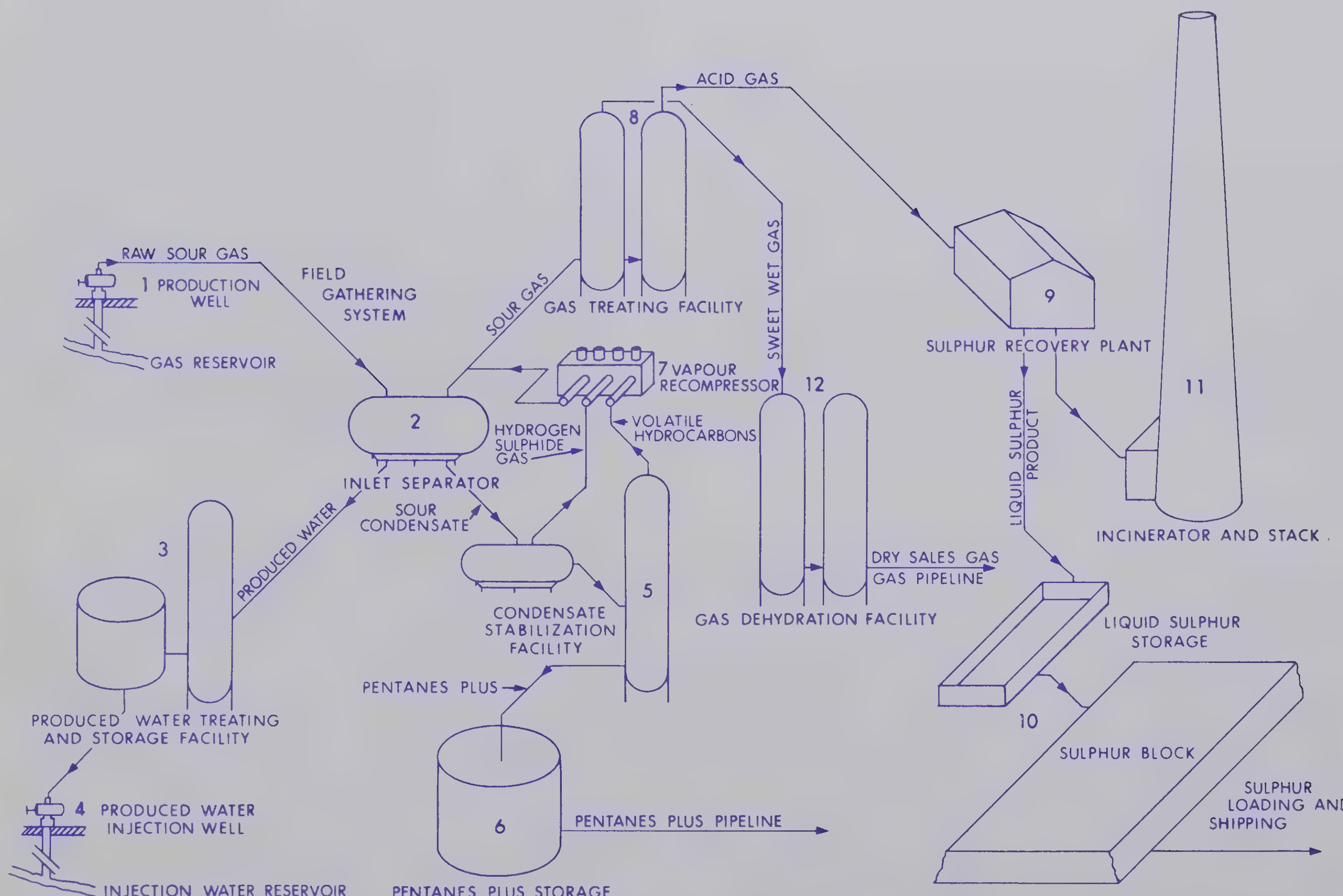
Gas processing includes a variety of processes each designed to suit the gas to be processed. In small sweet gas fields the processing facilities may only include separation equipment to remove liquid hydrocarbons and gas dehydrators to remove water from the raw gas. Large sour gas fields may require a complex installation valued at up to 100 million dollars with facilities to produce sales gas, propane, butanes, pentanes plus and sulphur products.

The plants in the Province range in capacity from one or two million cubic feet per day to the large pipe line extraction plants, the largest of which processes up to 2,000 million cubic feet per day of pipe line gas.

PROCESS DESCRIPTION

Although the process at each plant is different the same general operations take place to prepare the produced raw natural gas for market. The accompanying diagram shows a simplified outline of the major processes utilized in a plant which processes sour gas.

Gas produced from wells in the field (1) is delivered to the plant inlet separator (2) where gravity segregation is used to separate produced water and liquid hydrocarbons from the inlet gas stream. The produced water, which is normally saline, is treated and stored in tanks (3) before it is disposed of into deep injection wells (4), usually to the zone of origin. The sour hydrocarbon liquid removed from the inlet gas stream by the separator is referred to as condensate. Condensate flows to the condensate stabilization facility (5) where hydrogen sulphide and more volatile hydrocarbon vapours are removed. The pentanes plus product leaving this facility is similar in properties to an unrefined motor gasoline. It is stored in large tanks (6) before pipe line shipment to a refinery or chemical plant. Sour gas vapours from the



SIMPLIFIED GAS PLANT PROCESS FLOW DIAGRAM

inlet separator (2) and the condensate stabilizer vapour recompressor (7) flow to the gas treating facility (8). Here hydrogen sulphide and carbon dioxide contained in these gas streams are removed. The hydrogen sulphide — carbon dioxide mixture is referred to as acid gas and flows to the sulphur recovery plant (9). This facility produces a pure elemental sulphur product from the hydrogen sulphide through chemical reaction. The sulphur product is then stored (10) for sale. Unrecovered sulphur is incinerated to sulphur dioxide and emitted to the atmosphere through a tall disposal stack (11) designed to ensure that concentrations of sulphur dioxide do not exceed Provincial standards established for the protection of human, animal and plant life in the area. Sweet gas from the gas treating facility (8) contains water vapour which is removed by the gas dehydration plant (12) before entering a transmission pipe line.

BOARD RESPONSIBILITIES

The Board regulates most aspects of gas processing operations in the Province. A formal Board Approval is required before a new gas processing scheme can be constructed and before existing plants can be modified or expanded. Before issuing an approval the Board critically examines the proposed plant location, measurement facilities, conservation levels and pollution control features to ensure that all Provincial standards and regulations can be met.

Approvals contain conditions which in most cases specify the maximum raw gas and hydrogen sulphide inlet rate, the plant location, the minimum residue gas, the sulphur and natural gas liquids conservation efficiencies, the amount of flaring that may occur, the maximum permitted sulphur dioxide emission rate, the minimum permitted stack heights, the minimum ambient air quality monitoring network, the measurement and storage facilities, the disposal of plant waste water, the control of sulphur dust and, along with other provisions, specify reporting requirements.

Through recent research by the industry higher sulphur recovery efficiencies than previously possible can now be achieved. Recognizing its responsibilities respecting pollution control and the impact on the environment of the total sulphur dioxide emissions in the Province, the Board has recently developed sulphur recovery guidelines which will require an upgrading of recovery levels and a reduction in pollutant emissions. Required sulphur recoveries will range up to 99 per cent for the larger plants.

The Board also requires that each sour gas plant maintain a network of ambient air quality monitoring stations in the plant vicinity to determine air pollutant concentrations. The number and type of stations required vary with plant size. The results of this ambient air quality monitoring are reported monthly to the Provincial Department of the Environment, which also carries out its own independent monitoring to assist in determining whether Provincial standards are being met.

The Board's field staff periodically inspects all plants to ensure that the conditions in the Approval are being complied with. In addition, the operators of each sour gas processing plant are required to submit a monthly sulphur balance report to the Board's Gas Department. This report gives daily values for the volumes of sulphur processed by the plant, sulphur production, incinerator stack sulphur dioxide emission and other information important to pollution control at the plants.

The Board requires that the operators of sour gas processing plants conduct a certain number of stack surveys each year to provide additional data of the composition and quantity of stack gases being emitted to the atmosphere. Board staff also carry out a number of such surveys independently each year, as a cross check.

SUMMARY

The gas processing industry in the Province of Alberta has grown rapidly, particularly in the last twenty to twenty-five years. This industry is now a major contributor to the economy of Alberta. The Board regulates the industry in such a manner as to ensure that its growth takes place so as to serve the best interests of the people of the Province.

SUMMARY OF BOARD OPERATIONS — 1971

ORGANIZATION AND STAFF

As a result of passage of the Energy Resources Conservation Act effective June 1, 1971, the Board was expanded from three to five members. G. W. Govier, P.Eng. continued as Board Chairman, and D. R. Craig, P.Eng. and V. Millard were named Vice Chairmen. J. I. Strong, P.Eng. and N. Berkowitz were appointed Board Members.

The Board Solicitor provides legal advice and assistance directly to the Board. In addition, he may function as an Acting Board Member when appointed; he also chairs the Applications Advisory Group, which advises the Board on routine applications. The Managers of the Gas, Oil, and Development departments also serve on the Applications Advisory Group. The Staff Engineer reports directly to the Board, and is responsible for such items as the annual budget recommendation, the Educational Assistance Plan, the publication of several annual Board publications, and for other matters which are assigned by the Board. The Technical Assistant to the Chairman assists the Chairman with a variety of technical and administrative matters. Managers of all engineering departments, and other senior staff, may serve as examiners at public hearings. A list of the Board Members, Advisers, and Department Managers is provided on the inside back cover of this report.

During 1971, the Board established a Coal Department and a Hydro and Electric Department. The Coal Department, while still in its infancy, will be concerned with conservation, processing, resource appraisal, safety, and pollution control in the coal industry; the Department will also collect and analyze statistical data obtained from the coal industry. The Hydro and Electric Department, also in its formative stage, will collect and review data, and will process applications relating to the generation and transmission of electric energy.

The Gas Department is concerned with the conservation of gas, natural gas liquids, and sulphur. It also determines reserves, and is responsible for the assessment and surveillance of gas processing and cycling projects having regard for their affect on conservation and the environment.

The Oil Department's responsibilities are in the areas of ensuring conservation and protecting correlative rights in crude oil operations. It assesses enhanced recovery schemes, concurrent production schemes, maximum production rate limits, reserves, spacing, and technical matters relating to the Proration Plan. The Department also makes technical appraisals of, and handles the surveillance of, oil sands operations.

The Development Department, with its Drilling and Production Section and its Field Inspection Section, is responsible for the standards and the inspection of procedures and equipment used in the drilling and producing of wells. In addition, the Department is responsible for enforcing the Board's pollution control regulations.

The Geology Department provides geological interpretations of oil and gas reservoirs. The Core Storage Center catalogues and retains samples of drill cuttings and cores, and provides facilities for their examination by industry and the general public.

The Economics Department handles much of the administration of the Proration Plan, and conducts economic studies and appraisals related to conservation and other subjects. It also conducts major analyses and reviews of Alberta's future requirements for energy resources.

The Accounting Department is responsible for the processing and publication of all production and disposition statistics for oil and gas and related products. Its role is being expanded to cover similar work related to other energy resources. The Department also handles the Board's financial accounting.

The Data Processing Department is responsible for computer programming and systems design. An IBM/360-30 computer, supplemented when necessary by off premises computer facilities, provides a fully integrated,

organization-wide data storage, retrieval, and processing system.

The Office Services and the Personnel Departments complete the Board's organizational structure. These departments provide information and service to the public and the industries served by the Board, and also provide staff assistance within the Board.

IMPORTANT ACTIVITIES IN 1971

Oil industry activities in 1971 remained at about the same level as the previous year. There was a minor decrease in the number of exploratory wells drilled which was offset by an increase in the number of development wells drilled. Generally speaking, the results of exploration for oil and gas were disappointing. Exploratory and development drilling for gas was concentrated in the Medicine Hat, Alderson and Dunvegan areas and the most promising oil discoveries were made in the general Countess and Grand Forks areas. Experimentation in oil sands and heavy crude oil deposits continued at a slightly higher pace during 1971. Thermal recovery experiments continuted at Gregoire Lake and a new phase of the Cold Lake project was initiated.

During the year, the Board reported on the long term requirements of the Province for natural gas. The Board's findings were that some 15.8 trillion cubic feet (1,000 Btu's per cubic foot) of gas will be required for Alberta over the 30-year period 1970 to 2,000.

Three applications by Alberta and Southern Gas Co. Ltd., Consolidated Natural Gas Limited and Trans-Canada Pipe Lines Limited, to the Board requesting removal of gas from the Province were granted during the year, approving the removal of some 2.7 trillion cubic feet from Alberta. An application by Dome Petroleum Limited and Amoco Canada Petroleum Company Ltd. was also approved by the Board for the granting of a permit for the removal of 180 million barrels of ethane (equivalent to 543 Bcf of 1,000 Btu natural gas). The Board also considered applications from Dome Petroleum Limited and TransCanada Gas Products Ltd. and Dome Petroleum Limited and Amoco Canada Petroleum Company Ltd. requesting removal of propane from the Province and were granted permits for the removal of a total of 60 million barrels.

The Board approved an application by the Syncrude group to increase the permitted rate of synthetic oil production from its proposed plant, planned to start-up in 1976, from 80,000 to 125,000 barrels per day.

During the latter part of 1971, the Board heard an application by the Independent Petroleum Association of Canada for modifications to the current oil proration plan. The Board's decision on this application is pending.

Gas processing plant construction continued at a strong pace throughout the year with 13 new plants and 14 major expansions to existing plants built. The Aquitaine plant at Ram River was expanded to increase raw gas processing capacity from 220 to 382 MMcf per day including an increase in sulphur output from 2,000 to 4,100 long tons per day.

To ensure gathering and conservation of gas produced with oil, three gas conservation orders were issued during the year for the Ante Creek, Provost and Acheson East fields. These schemes will result in the conservation of an additional 4.8 billion cubic feet of gas.

New schemes initiated to enhanced recovery of conventional crude oil will result in the additional recovery of some 38 million barrels above that obtainable from primary recovery. Although there were no large schemes initiated in 1971 the schemes in the Pembina Keystone Belly River U Pool and two schemes in the Willesden Green Cardium A Pool accounted for about one-half of the 38 million barrel total. This improvement in recovery was offset by a reduction of some 70 million barrels of oil previously thought to be recoverable from the Pembina Cardium Pool. The downward revision was based primarily on a decrease in oil in place in the pool.

Pollution control continued to occupy a significant portion of the Board's workload in 1971. Although field inspections were increased on a Province wide basis, particular attention was given the Swan Hills and Pincher Creek areas. The Board also successfully abandoned two wells which were drilled about forty years ago. The wells were never properly abandoned and were causing serious pollution problems.

To reduce the emission of sulphur compounds from gas processing plants, the Board issued an Informational Letter No. 71-29 which set out guidelines outlining minimum sulphur recovery for various acid gasses expected in current and future processing plants.

New pollution control regulations were enacted which require the installation of special equipment on oil and gas wells to provide for the reduction of pollution in the event of a failure of a relief valve. The requirement by the Board of a monthly sulphur balance report, which was initiated during the latter part of 1970, proved to be very useful to the Board in its surveillance of sulphur compound emissions to the atmosphere. During 1971 the Board reviewed all of the existing sour gas processing plant approvals to check the adequacy of the presently required stack heights. This review resulted in the Board requiring improvements at some 10 plants and the improvements have been initiated by the operators but in most cases are not expected to be completed until 1972. The Board also participated in the Canadian Petroleum Association Oil Spill Contingency Plan, which provides for the formation of producing companies into co-operatives in oil fields to ensure containment and rapid clean-up of spilled oil.

To improve the Province's ability to respond to increasing conventional crude oil demand, a number of changes were made in the Board's proration system. A Purchasers' Committee was formed to ensure that nominations for crude oil are as accurate as possible and a procedure was instituted to improve the accuracy of expected monthly production which is supplied by operators each month. Daily reports of throughput will be supplied by the pipe line companies to provide up-to-date evaluation of production. Five companies operating high productivity pools have agreed to provide flexibility of supply by quickly increasing or reducing production when market demand changes occur late in a month.

Most of the Board's oil and gas reserve engineering work was focused on improving interpretation of reserves for existing pools and the surveillance of existing exhanced recovery schemes. The Data Processing Department's programs are allowing a greater amount of this work to be computer-assisted each year.

During 1971 the new Hydro and Electric Department issued a series of Interim Directives and commenced a review of regulations which are proposed to be enacted in 1972. A review of the service areas throughout the Province was also commenced in 1971 and will continue in 1972. An Interim Directive was issued to provide for the submission of statistical reports by industry. It is intended that this will be incorporated into the regulations in 1972.

The Board heard an application by Canadian Utilities, Limited for construction of an additional 150 megawatt generating station on the Battle River near Forestburg. The Board issued its decision on the application in October, 1971.

During 1971 preparations were made for the administration of The Coal Mines Regulation Act and The Quarries Regulation Act which were assigned to the Board on January 1, 1972. A preliminary draft of a proposed Bill for Coal Conservation was completed. Studies were made of the type of reports to be submitted by industry and of the methods for appraisal of Alberta coal reserves. The Board also held discussions with officers of the Coal Operators Association, the Northern and Southern Alberta Institutes of Technology and the Department of Education regarding the need for specific training programs for technicians to serve the coal industry.

The Board made preparations during 1971 for the assignment of the administration of The Pipe Line Act. The proclamation effecting the change was made on January 1, 1972.

Arrangements with the Department of Public Works for the completion of the fourth floor of the Board's Calgary office building to relieve space pressure and accommodation of the new Coal and Hydro and Electric Departments were made and are expected to be completed early in 1972. Extensions to the Board's Edmonton and Red Deer area offices were completed in 1971.

EXPENDITURES AND REVENUES

Total expenditure of the Board for the fiscal year April 1, 1971 to March 31, 1972 is estimated (January 15, 1972) at $4,180,000, of which some $3,887,000, $104,000, $112,000 and $77,000 are related respectively to the Board's oil and gas, hydro and electric, coal and pipe line operations. The last three amounts refer to expenditures for fractions of the year. The oil and gas related expenditures are 10.3 per cent above the corresponding expenditures for 1970-71. A significant part of this increase was due to the increased responsibilities assigned to the Board with respect to pollution control in oil and gas operations. Net expenditures for oil and gas operations after deducting sundry income increased from $3,012,000 in 1970-71 to $3,572,000 in 1971-72 or by some 19 per cent. The larger than average rate of increase to net expenditure was mainly caused in high non-recurring sundry income in 1970-71.

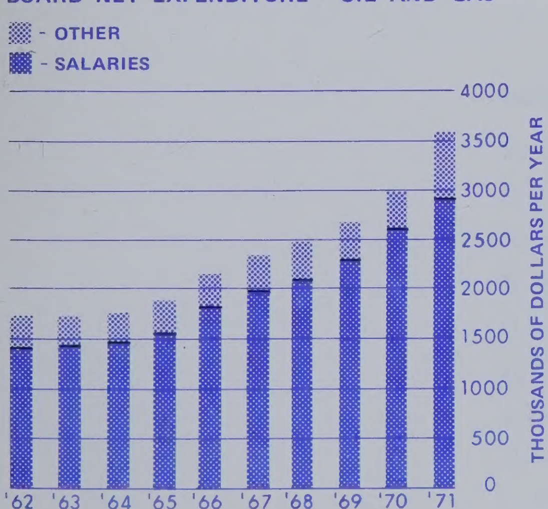
Total net expenditure for all Board operations for 1971-72 is estimated at $3,865,000.

Fifty per cent of the revenues to meet the Board's 1971-72 net expenditure related to its oil and gas responsibilities were provided by the Government of Alberta; a levy of a tax on oil and gas properties in the Province provided the remainder. The full cost of the Board's work relating to hydro and electric energy, coal and pipe lines was borne by the Government of Alberta in 1971-72.

An accompanying chart gives the historical trend of the Board's oil and gas related net expenditure divided between salaries and other costs. The abnormal increases in expenditures over the past two years were largely due to the Board's increased activity in pollution control work. A second chart shows the same net expenditure expressed in terms of cents per equivalent barrel of crude oil production. Over the past ten years the cost per equivalent barrel* of crude oil production has decreased from over one cent in the late 1950's to average between six and seven tenths of a cent during the last ten years.

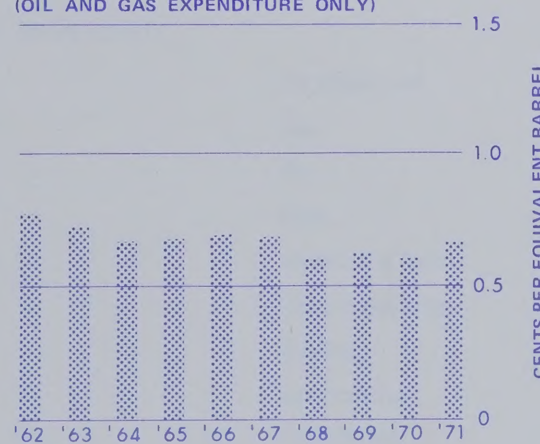
* Equivalent barrels — total industry production revenue divided by the weighted average price per barrel of oil.

BOARD NET EXPENDITURE - OIL AND GAS



BOARD NET EXPENDITURE PER EQUIVALENT BARREL OF CRUDE OIL PRODUCTION

(OIL AND GAS EXPENDITURE ONLY)



AS OF DECEMBER 31, 1971

BOARD MEMBERS

G. W. Govier	Chairman
D. R. Craig	Vice-Chairman
V. Millard	Vice-Chairman
J. I. Strong	Board Member
N. Berkowitz	Board Member

SENIOR ADVISERS

N. A. Macleod	Solicitor
G. A. Warne	Technical Assistant to the Chairman
A. F. Manyluk	Staff Engineer

DEPARTMENT MANAGERS

V. E. Bohme	Development
G. J. DeSorcy	Gas
N. A. Strom	Oil
W. A. Fowers	Coal
C. J. Goodman	Hydro & Electric
E. J. Morin	Data Processing
J. R. Pow	Geology
K. W. Fuller	Accounting
J. Rimell	Economics
R. F. Braun	Personnel
J. G. Anderson	Office Services